Microseismic monitoring of geomechanical reservoir processes and fracture-dominated fluid flow

ANDREW J. JUPE, ROBERT H. JONES, STEPHEN A. WILSON & JOHN F. COWLES

ABB Offshore Systems, Rosemanowes, Penryn, Cornwall, TR10 9DU, UK (e-mail: andrew.j.jupe@gb.abb.com)

Abstract: Microearthquakes (microseismic events) are induced during hydrocarbon and geothermal fluid production operations in naturally fractured reservoirs. They typically result from shear-stress release on pre-existing faults and fractures due to production/injection induced perturbations to the effective stress conditions. These stress changes may be due to reservoir depletion, flooding or stimulation operations. Over a number of years it has been shown that microseismic monitoring has the potential to provide valuable time-lapse 3D information on the geomechanical processes taking place within a reservoir. These processes include the distribution of fluid flow and pressure fronts within naturally fractured systems, production-related compaction and the reactivation of faults. With the advent of permanent reservoir monitoring systems (e.g. intelligent wells), microseismic monitoring has the potential to become a practicable means of time-lapse imaging of hydrocarbon reservoir processes remote from production/injection boreholes. This paper illustrates some of the ways in which microseismic monitoring can contribute to the development and management of hydrocarbon reservoirs through the presentation of examples from both hydrocarbon and geothermal reservoirs.

Throughout the life of a reservoir the hydrocarbon production process induces pressure changes within the reservoir. These changes result in perturbations to the *in situ* stress conditions that propagate through the reservoir. One of the key drivers for the development of 4D (3D time-lapse) reflection seismic data has been the operator's desire for time-lapse images of where and when these changes are taking place, and also their magnitude and impact on production. This information then feeds into the reservoir management process, particularly through integration into reservoir simulation and in the longer term through coupled hydro-geomechanical reservoir models.

An additional and direct consequence of these pressure and stress changes is the possibility of re-activation of pre-existing reservoir structures such as faults and fractures, which manifests itself as small earthquakes, referred to as micro-earthquakes or microseismic activity. In mature fields and fracture-dominated reservoirs the pressure and stress changes tend to be more severe and the seismic activity more intense. The following are three situations in which induced microseismic activity is likely to occur.

Reservoir depressurization can lead to localized reservoir compaction, or on a reservoir scale to compaction-assisted or compaction-driven production. In several North Sea fields where compaction is taking place there are associated problems of wellbore stability and integrity. Large-scale depressurization near fault-sealed or fault-compartmentalized reservoirs will lead to fault reactivation and the potential for pressure breakthrough into neighbouring reservoir compartments or even fields.

Enhanced recovery, particularly in mature fields, may require massive injection and flooding programmes aimed at pressure maintenance. Even in moderately fractured reservoirs the efficiency of these operations is known to be strongly affected by anisotropic or heterogeneous flood patterns.

Reinjection is also becoming an increasingly common approach to the disposal of waste from development and in-fill drilling, from increased solids and water production, and ultimately it may be used in seafloor waste recovery and disposal prior to decommissioning. The question being asked by operators and regulators is how can this process of reinjection be managed and the size and shape of disposal domains monitored.

This paper aims to demonstrate how induced microseismic activity can be used for continuous 3D time-lapse monitoring of these hydro-geomechanical processes and assist in the reservoir

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development and management. This is achieved through the presentation of data sets from three hydrocarbon reservoirs (Clinton County, USA, and Ekofisk and Valhall, North Sea) and also an example from the geothermal industry where the technique is already well established.

The origin of microseismic events

Microseismic events are basically small earthquakes, usually Richter magnitude (M_L) <0, and they have been detected and located at distances of over 1 km from the monitoring well in some hydrocarbon reservoirs, depending on seismic attenuation and complexity of the velocity structure. They occur because the Earth stresses acting within the reservoir are anisotropic. This causes shear stresses to build up on naturally occurring fracture surfaces that under normal conditions are locked together (Fig. 1). When the *in situ* stresses are perturbed by reservoir production activity, such as changing fluid pressures, the fractures can shear producing small earthquakes (Fig. 1). The seismic signals from these microseismic events can be detected and located in space using high bandwidth borehole geophones. Microseismic activity has been successfully detected and located in rocks ranging from unconsolidated sands, to chalks to crystalline rocks (e.g. Keck & Withers 1994; Ilderton *et al.* 1994; Deflandre *et al.* 1995; Wallroth *et al.* 1996; Maxwell *et al.* 1998; Warpinski *et al.* 1999; Snell & Close 1999; Bell *et al.* 2000; Maxwell & Urbancic 2001). Other potential sources of microseismic activity include the generation of new fractures through tensile splitting (e.g. conventional hydraulic fracturing) or pore collapse associated with compaction, that might produce implosion events. However, shearing mechanisms are generally believed to be the most common and also most energetic failure mechanism.

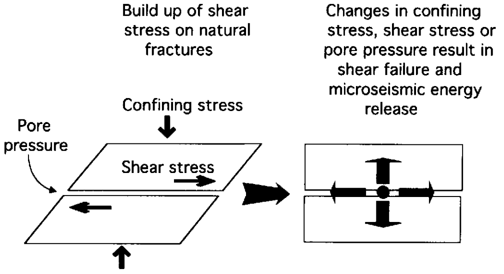

Fig. 1. Schematic of the main microseismic shear failure mechanism.

The examples presented in this paper illustrate the potential of microseismics to:

- identify fault structures that can result in reservoir compartmentalization or act as flow channels and routes for premature water breakthrough;
- image flow anisotropy associated with production from fracture-dominated reservoirs;
- provide real-time 3D monitoring of fluid pressure front movement, such as water flood fronts;
- assist in targeting new producer/injector wells;
- identify areas of reservoir compaction and potential wellbore instability;
- Provide input and condition permeability grids for reservoir simulation.

Fracture zone controlled water production (Clinton County, Kentucky, USA)

Clinton County, Kentucky is located within the Cumberland Saddle of the Cincinnati Arch, immediately west of the Grenville Front. The reservoir in this field consists of a low porosity carbonate within which fracture storage and permeability are suggested by isolated, high-volume production wells which subsequently produced brine (Phillips *et al.* 1996). Initial production rates as high as 400 barrels per hour and cumulative production of 100000 barrels from a single well have been reported.

Basement-controlled wrench-fault structures have been associated with oil production from shallow (135–180 m) carbonate reservoirs 65 km west of Clinton County. Operators have based drilling programmes on fracture/lineament patterns delineated from radar images and interpreted as being associated with wrench faulting of an east–west trending basement fault.

Several programmes of microseismic monitoring have been carried out by personnel from the Los Alamos National Laboratory during production to help identify active and possibly producing fault structures (e.g. Rutledge *et al.* 1994; Phillips *et al.* 1996). Microseismic results reported by Phillips *et al.* (1996) defined three low-angle, reverse slip fracture zones (Fig. 2), where the seismic activity was clearly related to the production of over 8100 barrels of oil from well HT1. Rutledge *et al.* (1994) also reported similar structures from other parts of the field. The mapped fractures fell above and below the HT1 production interval, but intersected or could be mapped to old production well intervals (GT1, GT2 and GT4). A cumulative volume of 4600 barrels of oil was extracted from these three wells in the nine months preceding monitoring.

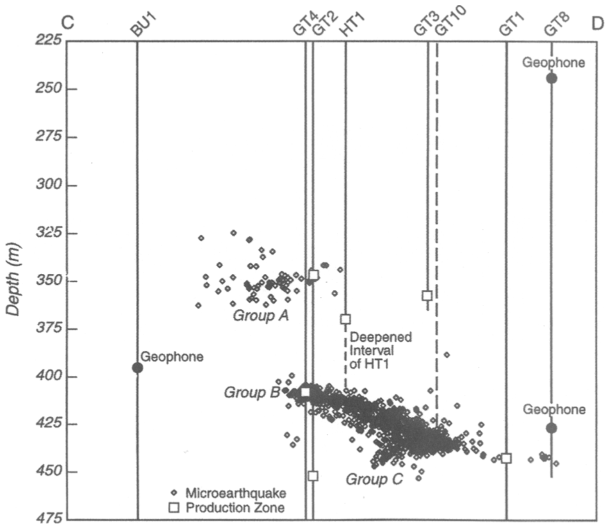

Fig. 2. Cross-sectional view of microseismic activity at Clinton County (after Phillips *et al.* 1996). Reproduced with the kind permission of the SPE.

Well GT10 was subsequently drilled into the main mapped fracture and produced brine. Later well HT1 was deepened, encountering brine within 3 m of the same mapped fracture. The interpretation is that the microseismic monitoring defined oil-bearing producing fractures that subsequently filled with brine, presumably from an active, but in this case poorly connected water drive.

The presence of these low-angle, oil-bearing faults has implications for field development. Drilling horizontal or deviated wells does not increase the probability of intersecting productive fractures in Clinton County. However, inter-well correlation and mapping of the conductive fractures could allow better planning of plug and abandonment operations, so as to avoid premature contamination of the main pay zone with water. Pressure maintenance operations are also being considered once the fracture zones between the wells have been mapped.

The results obtained in Clinton County are a clear illustration of how microseismic imaging of active fractures can assist in identifying fracture-controlled water breakthrough and assist planning reservoir development.

Monitoring fractured and compacting chalk reservoirs (Ekofisk and Valhall, North Sea)

In 1997/98 microseismic monitoring trials were conducted in the Ekofisk and adjacent Valhall fields, operated by Phillips Petroleum and BP-Amoco respectively. Both fields comprise highly productive naturally fractured chalk reservoirs that are undergoing varying levels of production-induced compaction.

In April 1997 an 18–day microseismic monitoring trial was conducted in the Ekofisk field (Maxwell *et al.* 1998; Dangerfield *et al.* 1999). The monitoring system consisted of a six-level triaxial VSP wireline tool deployed within the reservoir, in an observation well (2/4–C11a) located near the crest of the field. Approximately 2100 microseismic events were recorded, corresponding to roughly five events per hour at distances of at least 1 km from the observation well. The majority of the events were located in the upper part of the reservoir, predominantly within low-porosity layers overlying relatively porous layers which are undergoing water flooding and compaction (Fig. 3). Events were most accurately located near the monitoring borehole, with the location of events further away being more uncertain. Within 300 m of the well most events were precisely located to an accuracy of better than 30m.

Locations of the events close to the monitoring well (C11A) were obtained with a 3D-velocity model, which is particularly accurate in this region due to the large number of wells. Figure 4 shows that the events around C11A cluster along discrete linear bands. These linear clusters are interpreted to result from induced movements on pre-existing faults. They have the same orientations as the majority of the faults

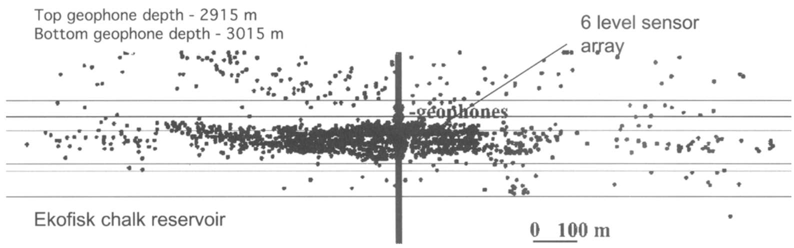

Fig. 3. Vertical cross-section showing the location of the microseismic events and major reservoir layers at Ekofisk (after Maxwell *et al.* 1998).

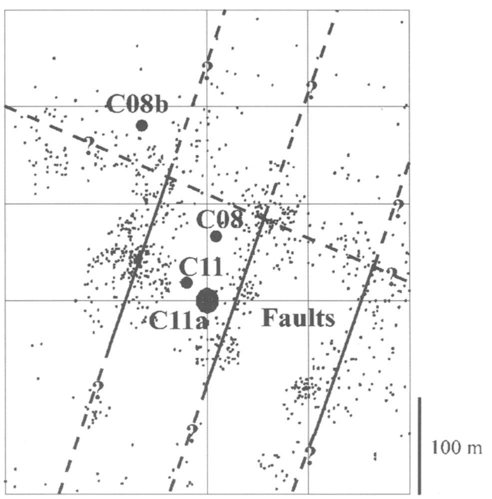

Fig. 4. Map view of events showing distinct lineations attributed to induced movement on pre-existing faults at Ekofisk (after Maxwell *et al.* 1998). Well C11A is the monitoring well.

within the reservoir (NNE-SSW and NW-SE). These results are particularly useful because this portion of the field is not imaged by the normal surface seismic methods due to the presence of crestal gas cloud.

A comparison was made between a numerical waterflood simulation and the positions of the induced microseismicity (Maxwell *et al.* 1998). Only events above magnitude –2 were included, corresponding to the magnitude range where all events are detected independent of distance. Comparisons with simulations of the waterflood front indicated that the saturated zones around the injection wells were aseismic. However, the position of the waterflood front was not known accurately enough to test if any of the clusters of microseismicity were associated with it. Nevertheless the results are encouraging despite the relatively short monitoring period. The compaction of the chalk layer may be strongest at the waterfront. If a significant proportion of the total acoustic activity is caused in association with the waterfront, then time-lapse microseismic monitoring could represent a useful tool for tracking the position of the water flood.

In summary, microseismicity was successfully recorded and processed using a VSP sonde in a single borehole in Ekofisk. Events were accurately located and found to be concentrated in the low-porosity sublayers. Close to the monitoring well the microseismicity clustered in specific lineations in plan view, believed to be reactivation of pre-existing faults. The dynamic relationships between fault movements, reservoir compartmentalization compaction and waterflood are clearly complex. It will require longer test to see if these mechanisms can be isolated; however, this initial study was highly encouraging.

The Valhall field, which is adjacent to Ekofisk, has been producing oil since 1982 (Dyer *et al.* 1999). It currently produces in excess of 100 000 barrels of oil per day. Estimated original oil in place is 2.4 billion barrels, of which 640 million barrels can be recovered under the current plan. Development drilling is still ongoing. The field is recognized as one of the most challenging in the North Sea. The reservoir is relatively thin, structurally complex and covers a 50 km^2 area. It was formed as a slightly asymmetric anticline by inversion along the major Skrubbe fault that lies west of the field.

While 3D seismic data play an essential role in assessing depletion of the structures flanks, gas charging of the overburden has severely distorted the seismic image in the crestal part, as in Ekofisk. The reservoir rock is weak, highly porous Cretaceous chalk that undergoes significant compaction when depleted. Fracture permeability and compaction compensate for generally low chalk-matrix permeability. Horizontal wells have significantly improved recovery.

Although compaction of the chalk adds to oil recovery, it also results in the overburden deformation. This implies seafloor subsidence (currently 3.5 m) and a negative impact on well life. Overburden deformation associated with compaction calls for special wells and casing design, in both overburden and reservoir zones. Still one or two wells per year are lost due to permanent failure or casing collapse.

Most of the horizontal wells are completed by multiple proppant fracturing with up to five or six fractures in one well. The ability to monitor and qualify these stimulations is currently limited to using overall production data. Additional observations that could be used to delineate the magnitude and direction of fractured zones would be very valuable in optimising wellbore stimulation.

A microseismic monitoring trial (Dyer *et al.* 1999) was conducted to see if the technique could provide information on:

- deformation mechanisms;
- poor seismic control in the crestal area;
- wellbore stability issues associated with subsidence;
- dominant stress orientation;
- feasibility for monitoring proppant fracturing in the reservoir.

As with Ekofisk a single six-level VSP wireline tool was deployed in a monitoring well. In addition to its location in the crestal part of the reservoir it was only a few hundred metres away from a well that was being sidetracked during the monitoring period, with hydraulic fracturing of the reservoir planned when drilling ended. The unfortunate limitation was a clay plug in the bottom hole section of the monitoring well which caused the geophone array to be located 250 m shallower than planned and above the top reservoir. This increased seismic attenuation and significantly reduced the number of events detected.

Frequency of microseismic event rates ranged from none to ten per day. During the 57-day monitoring period 572 events were detected, of which 324 could be reliably located. The event rate was about 10% that observed in the Ekofisk field. This appears to be due to the high attenuation of the low velocity sequence between the geophones and reservoir, and the fact that the sensor string could not be deployed as close to the reservoir as it had in Ekofisk, where the deepest geophones were within the reservoir. This means that only nearby or more energetic events were detected.

All located events except those related to drilling activities were located within a 50 m thick zone directly above the Top Balder reservoir formation. The limited vertical and lateral distribution of the microseismic events indicated that the microseismicity was related to reservoir production rather than random background seismicity. This is a major zone where wellbore stability problems are experienced. From event locations two potential structures were interpreted (Fig. 5). These events are shown as ellipsoids representing one standard deviation of the event location uncertainty. Analysis of the focal mechanisms of events in these lineaments indicated a significant normal-faulting component. Although the direction of the lineaments does not necessarily indicate fault strike it is likely to be the case in Valhall. These lineaments indicated two sets of fault directions: one roughly NW and SE and the other roughly SW to NE. This agrees with the current fault pattern model for Valhall.

As with Ekofisk this survey proves a high level of microseismic activity in the Valhall field that is

Fig. 5. Plan view of one standard deviation confidence ellipsoids for event locations in Valhall (after Dyer *et al.* 1999). Note clustering of event locations into two planar structures. Green sphere indicates location of geophones.

most likely related to reservoir production. The observed microseismic activity agrees with general fault trends and occurs in a zone with significant wellbore stability and integrity problems.

Geothermal reservoir development and management (Soultz-sous-Forets, Alsace)

The Soultz European Hot Dry Rock (HDR) experimental site (Baria *et al.* 1999) is located in the Rhine Graben *c.* 50 km north of Strasbourg. The geology comprises *c.* 1.5 km thick sedimentary cover overlying granitic basement. The geothermal reservoir itself is 2.5 to 4 km in depth in a faulted horst block, with rock temperatures of >160°C at 4 km depth. The system has been developed progressively since 1992, through a series of reservoir stimulation and characterization operations. In 1995 this led to the targeting and drilling of a second deep (4 km) borehole, creating a circulating HDR system. The first major development phase took place in 1993 with the large-scale stimulation (massive hydraulic fracturing, MHF) of a single deep borehole GPK1 (Fig. 6), over a 700 m open-hole length (2800 to 3500 m). This operation comprised the injection of 45 000 m^3 of water at flowrates up to $50\,l\,s^{-1}$ and overpressures of *c.* 10 MPa. The operation was aimed at opening up the existing fracture system, thus reducing flow impedance.

The operation was monitored using a network of three permanent four-component downhole accelerometers (1.5 km depth) and a single hydrophone, deployed in observation boreholes (Jupe *et al.* 1999). During the course of the operation 18 000 microseismic events were detected and located (Fig. 6). These formed a roughly ellipsoidal cloud with a NW–SE to north–south alignment (Fig. 7), a vertical extent of *c.* 1.2km and horizontal dimensions of *c.* 800 m and 150 m (Fig. 6).

At shallower depths (<3000 m) it was found that the near-wellbore growth direction was more north–south (close to the maximum horizontal stress direction σ_H) and believed to be controlled by the tensile opening (jacking) of fractures subparallel to σ_H. At greater depths, where the overpressure was lower compared to σ_H, the growth direction was more NW–SE; indicative of shear-failure-dominated growth along pre-existing fractures.

The hypothesized opening up of near-wellbore fractures at shallower depth was further confirmed by flow logging, where *c.* 60% of the flow left the borehole in the first 100 m of openhole, and by the microseismic depth distribution, with *c.* 70% of the microseismic events occurring at shallower depths than 3000 m.

Following the 1993 stimulation a series of reservoir characterisation operations were undertaken in 1994, at which time the microseismic activity was used to target a second deep (4 km) borehole GPK2. The objectives with this borehole were to achieve a hydraulic connection to GPK1 over the deepest (hottest) sections of the reservoir, thus maximizing recovery temperatures. The anisotropy of the microseismic cloud clearly dictated that the borehole should be located either NW or SE of GPK1, but that the deepest connection (3500 m) would be achieved by drilling to the S–SE, also satisfying a second criterion of a well separation of *c.* 350 m.

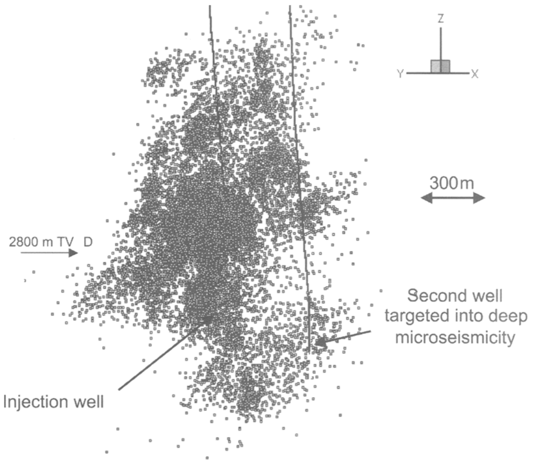

Fig. 6. Side elevation of microseismic activity detected during the 1993 massive hydraulic fracturing (MHF) of GPK1, Soultz. Well separation is approximately 350 m.

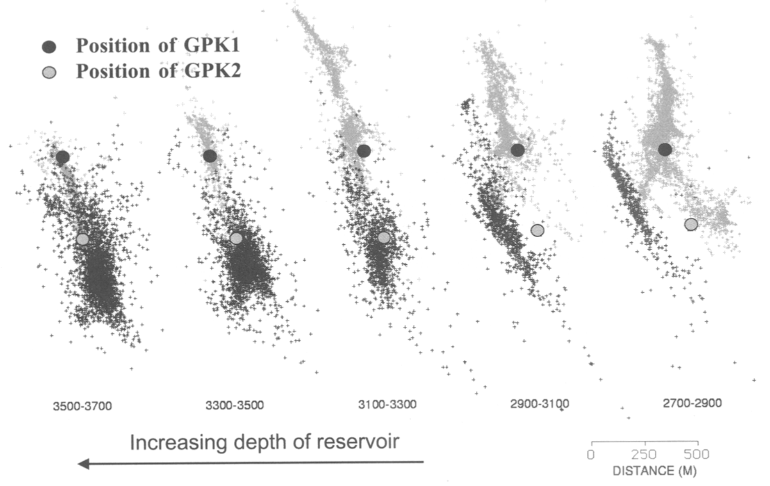

Fig. 7. Plan view of 300 m thick depth slices through the 1993 (GPK1) and 1995/96 (GPK2) MHF data sets.

In 1995/96 the second borehole GPK2 was stimulated at flowrates up to $80\ \mathrm{l\ s^{-1}}$, reaching downhole overpressures of *c.* 12 MPa. Over 12 000 microseismic events were detected (Fig. 8), forming a NW–SE trending structure, encroaching on the deepest sections of the GPK1 microseismic cloud and extending as far as the GPK1 borehole (Fig. 7). The GPK2/GPK1 reservoir was then successfully tested through a series of circulation operations. Long-term reservoir circulation (injection/production) started in 1997, accompanied by production logging, hydraulic and inert tracer tests.

The results of production logging during circulation indicated that flow exits were distributed along the entire openhole length of GPK2, but that flow entry into GPK1 occurred at two discrete intervals; at the bottom of GPK1 and in the upper section of GPK1 close to the casing shoe. The results of the microseismic monitoring (Fig. 8) demonstrated a strong correlation with this flow path distribution, indicating intersections with GPK2 over the entire openhole length and two apparent intersections with GPK1. This observation prompted an investigation into whether the microseismic event distribution from the Soultz reservoir could be used to construct a quantitative fluid flow model for reservoir performance prediction and use in reservoir development decisions.

Simulator grid construction

The microseismic data from the two MHF treatments has been analysed in terms of event spatial density and connectivity. This information is then mapped to a grid of reservoir simulator cells. The degree of grid connectivity and the scaling of cell hydraulic properties (i.e. pipe conductivity) is based on the analysis of microseismic attributes for the cells (i.e. density, cumulative energy release, cumulative shear slip) in conjunction with the measured hydraulic properties of the system (i.e. flow logs). Once constructed the grid of simulator cells is then input into a steady-state flow model and the simulation results compared with observations from the water circulation (i.e. flow logs, fluid recovery and inert tracer results). Figure 9 presents the fluid pressure field and flow distribution obtained from simulations of the circulation conducted in 1997 between GPK1 (injector) and GPK2 (producer). Figure 9 shows the most direct flow path between the two boreholes, in which flow leaves the bottom of GPK1 and is recovered in GPK2. This flow path represents the shortest breakthrough time of inert tracer (*c.* 4 days). A second significant flow path is observed in the upper section of GPK1, however this is seen to move out of the plane between the two wells. Fig. 9 demonstrates that this is in fact a hydraulic connection between the two wells, but is more tortuous than the deeper connection. This movement of fluid out of the plane of the two wells results in a longer tracer recovery time than the deeper connection. Both the deep and more shallow flow exits correlate well with the results of flow exits/entries in production logs.

Both the spatial distribution of the major water flow paths remote from the wellbore, and reasonable estimates of tracer transport times

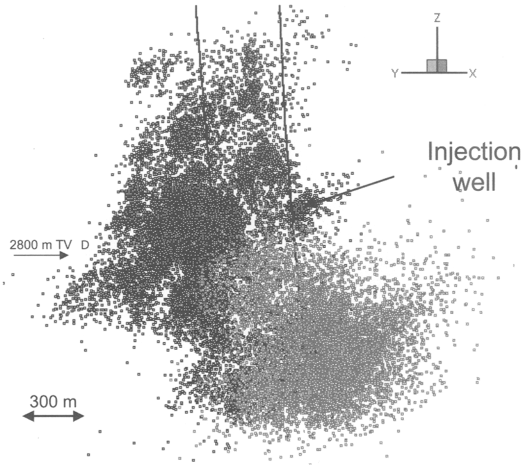

Fig. 8. Side elevation of microseismic activity detected during the 1993 MHF of GPK1 (left) and 1995/96 MHF of GPK2 (right). Well separation is approximately 350 m.

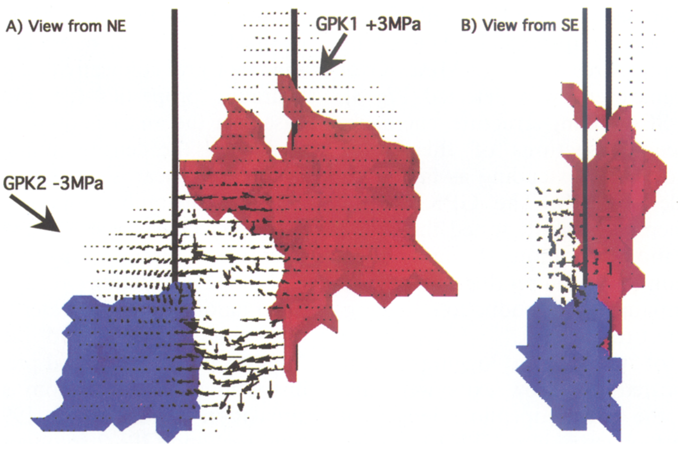

Fig. 9. 3D steady-state fluid pressure iso-surfaces (is ± 3 MPa) and flow vectors calculated for circulation between GPK1 and GPK2. The length of the flow vector arrows represents the magnitude of the flow velocity. Note that the flow vectors also indicate discrete flow paths that are out of the plane between the two wells. (**a**) View from NE; (**b**) view from SE.

between boreholes can be reproduced from this analysis of connectivity. This work confirms the importance of flow path geometry (i.e. anisotropy and heterogeneity) in controlling the flow behaviour of naturally fractured systems and highlights the significance of microseismic imaging for reservoir characterization and monitoring.

In summary, the key contributions to the development and management of this naturally fractured geothermal reservoir have been the following:

- Microseismic monitoring was successfully used to monitor the growth direction and extent of a series of Stimulation (massive hydraulic fracturing) operations at the Soultz site.
- Microseismicity has been used to identify discrete flow paths and quantify the flow/pressure field within the reservoir.
- Microseismicity has been used successfully to target a water injector well at a depth of around 4 km.

- Microseismicity has been used to assess 3D reservoir volume and shape, and hence quantify the success and efficiency of reservoir development operations.
- Results of the initial GPK1 stimulations directly influenced the parameters of the later GPK2 hydraulic operations.
- Microseismicity has been successfully used to construct a reservoir simulator grid for modelling the long-term behaviour and development of the geothermal system.

Summary

Microseismic imaging is well developed in geothermal applications and is directly applicable to the monitoring and management of hydrocarbon reservoirs, where it offers a high resolution means of continuous monitoring of the hydro- and geomechanical processes taking place within an evolving hydrocarbon reservoir.

The examples illustrate the potential of microseismics to:

- identify fault structures that can result in reservoir compartmentalization or act as flow channels and routes for premature water breakthrough;
- image flow anisotropy associated with production from fracture-dominated reservoirs;
- provide real-time 3D monitoring of fluid pressure front movement, such as waterflood fronts ;
- assist in targeting new producer/injector wells
- identify areas of reservoir compaction and potential wellbore instability;
- provide input and condition permeability grids for reservoir simulation.

Despite the potential of the technique there have been barriers preventing its widespread uptake by the industry. However, the industry is now more open to new ideas and 'step changes' in technology. In particular 4D seismic has succeeded in moving the focus from static reservoir models to understanding more about long-term reservoir behaviour and production processes in the inter-well region. The remaining technological difficulty is the deployment of permanent seismic sensors in production well completions; however, this barrier is also disappearing through the emergence of permanent borehole sensor installations and intelligent well completion technology, with subsurface sensor installations, dedicated telemetry systems and well control devices. Service companies are now introducing permanently deployed seismic systems into their product ranges (e.g. Deflandre *et al.* 1995; Hottman & Curtis 2001) and operators are beginning to trial these systems in intelligent well deployments (e.g. Bell *et al.* 2000). Soon it will be possible to fully exploit the 'grunts and groans' induced by hydrocarbon production.

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